STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Commerce Commission on Its Own Motion Northern Illinois Gas Company d/b/a Nicor Gas Gas Company Reconciliation of Revenues collected under Gas Adjustment Charges with Actual Costs Prudently Incurred	)	Docket No. 01-0705
Illinois Commerce Commission on Its Own Motion Northern Illinois Gas Company d/b/a Nicor Gas Company Proceeding to Review Rider 4, Gas Cost Performance Program, pursuant to Section 9-244(c) of the Public Utilities Act	)	Docket No. 02-0067
Illinois Commerce Commission on Its Own Motion Northern Illinois Gas Company d/b/a Nicor Gas Company Reconciliation of Revenues Collected under Gas Adjustment Charges with Actual Costs Prudently Incurred	)	Docket No. 02-0725

Direct Testimony on Reopening of

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Managing Director
Navigant Consulting, Inc.

On Behalf of
Northern Illinois Gas Company
d/b/a Nicor Gas Company

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TABLE OF CONTENTS

Page

I. Introduction and Qualifications

Q. Please state your name, business address, and current position.

A. My name is Russell A. Feingold and my business address is 200 Wheeler Road, Suite 400, Burlington, Massachusetts 01803. I am employed by Navigant Consulting, Inc. ("NCI") as a Managing Director and lead the Regulatory & Fuel Resources Group within NCI's Energy Practice. I have been employed by NCI since January 1997.

Q. Please describe the business activities of NCI.

A. NCI is a specialized independent consulting firm providing professional services to assist clients in identifying practical solutions to the challenges of uncertainty, risk and distress. We focus on large industry segments that are typically highly regulated and are undergoing significant change.

NCI has served the electric and natural gas industries since 1983. We offer a wide range of consulting services related to business strategy and planning, operations advisory management, financial and transaction advisory activities, and technology and innovation management designed to assist our clients in a business environment of changing regulation, increased competition and evolving technology.

From an industry-wide perspective, NCI has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies. This experience has been gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide variety of client assignments. NCI has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over 27 years of experience in the utility industry, the last 25 years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning.

Prior to joining NCI, I was a Vice President at R.J. Rudden Associates, Inc. Before that time, I was Director, Gas Regulatory Services at Price Waterhouse, and an Executive Consultant in the Regulatory Services Group of Stone & Webster Management Consultants, Inc. Prior to entering the consulting field, I was Utility Rate Specialist and Staff Engineer at the Port Authority of New York and New Jersey. In that role, I was responsible for designing and constructing electric power distribution systems for large public authority facilities in the New York metropolitan area, and working closely with the local electric utilities on various regulatory, ratemaking, and service issues.

I am closely involved in the regulatory, ratemaking, and marketing activities of the American Gas Association ("A.G.A.") through my leadership role in its ongoing training and industry seminar activities, and have spoken and written widely on issues such as energy industry restructuring, product and service unbundling, marketing of retail utility services, gas merchant services strategies, and regulatory reform initiatives. As part of my responsibilities, I have been the course organizer and an annual speaker since 1985 at the A.G.A. Gas Rates Fundamentals Course at the University of Wisconsin – Madison, co-sponsored by The Center for Advanced Studies in Business. In addition, I am a contributing author and technical editor of the latest edition of the A.G.A. “Gas Rate Fundamentals” textbook, and have published or presented over 45 articles and speeches relevant to the gas utility industry on issues and activities dealing with the pricing and marketing of gas and electric utility services.

On over 100 occasions, I have prepared and presented expert testimony before the Federal Energy Regulatory Commission (“FERC”) and several state and provincial regulatory commissions. My testimony has dealt with the costing and pricing of energy-related products and services for gas and electric distribution utilities and gas pipeline companies. In addition to traditional utility costing and rate design concepts and issues, I have addressed gas transportation rates and customer choice program design, gas supply planning issues and activities, market-based rates, competitive market analysis, gas merchant service issues, strategic business alliances, market power assessment, merger and acquisition analyses, multi-jurisdictional utility cost allocation issues, inter-affiliate cost separation and transfer pricing issues, seasonal rates, cogeneration rates and pipeline ratemaking issues related to the importation of gas into the United States.

I hold a BS degree in Electrical Engineering from Washington University in St. Louis and an MS degree in Financial Management from the Polytechnic University of New York.

Further background information presenting my education, presentation of expert testimony and other industry-related activities is included in Appendix A to my direct testimony.

Q. Please describe your specific experience in the area of Performance-Based Ratemaking ("PBR").

A. In the area of PBR, I have actively participated in projects that address the assessment, development, and implementation of PBR concepts for both gas and electric utilities. My work in this area has included assisting utilities with both margin-related concepts (e.g., price caps, shared earnings mechanisms) and fuel-related concepts (e.g., gas cost mechanisms). Besides assisting in the development of the strategic and computational aspects of the proposals, I have provided ongoing support to clients to ensure stakeholder acceptance and successful operation of the chosen PBR mechanism.

Q. Have you previously testified before the Illinois Commerce Commission ("ICC" or the "Commission")?

A. Yes. I previously testified on behalf of Northern Illinois Gas Company (d/b/a Nicor Gas Company) before the ICC in Docket No. 88-0277 on the subjects of gas rate design issues, and fully allocated and marginal cost of service studies, and on behalf of Central Illinois Public Service Company and Union Electric Company in Docket No. 99-0121 on the subject of functionalization of plant and expenses in support of establishing the utilities' revenue requirements for their delivery services function.

II. Purpose of Testimony

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony in this proceeding is to review the Gas Cost Performance Program ("GCPP" or "Program") approved, as modified, by the Commission, for Nicor Gas Company ("Nicor Gas" or "Company") and to present the results of my analysis on: (1) the purpose, design, and mechanics of the GCPP compared to gas cost PBR programs of other gas utilities in the U.S.; (2) the types of gas market conditions faced by Nicor Gas during the GCPP Period; (3) the manner in which Nicor Gas managed its gas supply resources under the approved GCPP; (4) the Company's use of its underground storage resources in managing the new risks created by the GCPP Benchmark and the gas market conditions experienced during the GCPP Period, and in deriving benefits for its customers and shareholders; and (5) the level and type of benefits provided to Nicor Gas's customers from the GCPP.

In order to conduct my analysis, I reviewed documents provided to me by legal counsel (which had been made available to the ICC Staff and intervenors) and publicly available documents I obtained through my independent research efforts, and interviewed various Nicor Gas personnel.

My analysis and related opinions on these topics are presented within the context of the approval process for the GCPP, the operation of the GCPP during the three-year period, January 1, 2000 through December 31, 2002, and the broader gas industry market conditions experienced during that same time period.

III. <u>Summary of Conclusions</u>

Q. Please summarize your conclusions in this proceeding.

A. During the course of NCI's review of the GCPP approved by the Commission, I analyzed various operational, ratemaking, and regulatory issues associated with the design, implementation, and operation of the GCPP. As a result of this review, I reached the following conclusions:

1. The GCPP approved by the ICC was similar in concept and operation to the structure of gas cost PBR programs of other gas utilities in the U.S.

2. In its approval of the GCPP, the Commission did not require Nicor Gas to share or make public the specific strategies that the Company would use to manage the gas resource portfolio under the GCPP.

   The Commission's Order approving the GCPP ruled that "specific information about the steps which Nicor Gas will take to save money" is not required for approval of the GCPP, and stated that, "Section 9-244 does not require that mechanisms which may generate customer savings be specifically articulated."

   Nicor Gas's broad strategies and specific tactical actions to manage its gas supply portfolio to the GCPP Benchmark evolved over time and were greatly affected by the volatile natural gas market conditions that occurred during the GCPP Period.

3. The GCPP approved by the Commission created new risks for Nicor Gas's customers and shareholders that the Company would have to successfully manage to derive benefits under the GCPP from its gas supply planning and procurement activities.

   Recognition of these new risks provides an understanding of the approaches Nicor Gas could use to manage these risks in its efforts to create the benefits for its customers and shareholders.

4. The challenging gas market conditions experienced during 2000 through 2002, under which Nicor Gas was required to manage its gas resource portfolio to the GCPP Benchmark, reflected very unpredictable weather patterns, unusual swings in gas demand requirements, highly volatile gas prices, and precipitous industry restructuring.

5. The Company's use of its low-cost LIFO gas layers in underground storage was a reasonable, appropriate, and effective risk-mitigation strategy for managing its gas resource portfolio to the GCPP Benchmark and for deriving benefits for its customers and shareholders.

The low-cost LIFO gas storage layers were, and remain, the assets of Nicor Gas, and were available for the Company's use during the GCPP Period just as any other utility-owned resource within its overall gas supply portfolio.

The use of these low-cost LIFO gas layers was a reasonable, appropriate, and effective strategy for the Company to access and monetize the value of its trapped LIFO layers and to share the realized value with its customers through the GCPP.

It is a reasonable risk management practice for a gas utility such as Nicor Gas to rely upon its gas storage assets in periods of high market volatility to minimize the level and variability of the gas costs incurred to serve its sales customers.

The ICC was aware of the potential availability and unrealized value of Nicor Gas's low-cost LIFO layers for their eventual use in the GCPP.

6. Under Nicor Gas's management, the GCPP yielded a substantial benefit to its customers of approximately $53 million, and these gas cost-related benefits would not have been realized in the absence of the GCPP.

IV. <u>Background Context for NCI's Review of the GCPP</u>

Q. Please explain the background context for NCI's review of the GCPP.

A. As background context for our review of the GCPP, I prepared various materials that address the following topics related to the GCPP approved by the Commission. These topics were:

1. The conceptual underpinnings of gas cost-related PBR programs

2. The regulatory history of the GCPP

3. The purpose, design, and mechanics of the GCPP

4. Comparison of Nicor Gas's 1996 and 1999 GCPP filings and the GCPP approved by the Commission

This material is provided in Appendix B to my direct testimony and is summarized below.

Q. Can you briefly summarize the conceptual underpinnings of gas cost-related PBR programs?

A. Yes. The conceptual underpinnings of gas cost-related PBR programs consist of the following considerations:

- PBR describes an alternative regulatory and ratemaking framework that provides a utility with a stronger incentive to control costs, and the resulting prices to its customers, than under traditional cost of service regulation. PBR mechanisms fundamentally change the rate setting process from a singular focus on cost recovery to one focused on financial and operational incentives. As such, the utility has a strong motivation to control costs because it can retain some level of financial benefits associated with improving the efficiency of its operations, and because it has a reduced ability to pass on cost increases typically allowed under cost of service regulation.

- If properly structured, the incentives contained in the PBR program should motivate the utility to increase its efforts, and to change its behavior to embrace the added managerial and operational flexibility afforded under PBR, to the ultimate benefit of both its customers and shareholders. Through this process, a desirable outcome of the PBR program will be a closer alignment of a utility's customer and shareholder interests.

- Critical to the success of a gas cost PBR program is the choice of benchmark. It should reasonably reflect the components of the utility's gas supply portfolio that are subject to the PBR mechanism without making it overly complex to calculate and verify, and it should represent a proper "market standard" for measuring the performance of the utility's gas supply portfolio.

Q. Please summarize the regulatory history of the GCPP.

A. The regulatory history of the GCPP is summarized below:

- Nicor Gas initially filed its GCPP proposal in August 1996 (Docket No. 96-0386).

- Nicor Gas filed a motion in January 1997 requesting that its GCPP filing be withdrawn. The Commission subsequently approved the motion to withdraw the petition.

- Nicor Gas filed a second petition for the approval of a GCPP in March 1999.

- In a November 1999 Order, the Commission approved the GCPP proposed by Nicor Gas, with certain modifications.

- Nicor Gas accepted the GCPP in December 1999, as amended by the Commission.

- The GCPP was implemented on January 1, 2000.

Q. Please briefly describe the purpose, design, and mechanics of the GCPP.

A. The purpose, design, and mechanics of the GCPP can be described as follows:

- Create for Nicor Gas the appropriate economic incentives to encourage further improvement in gas supply, transportation and storage acquisition and management, thus providing customers with the best gas prices available, consistent with the need for reliability and security of supply;

- Establish a reasonable balance between risk and reward, thus encouraging the appropriate use of competitive market opportunities and risk management mechanisms for Nicor Gas's procurement of gas supply, transportation and storage services for customers; and

- Establish an objective standard for evaluating gas supply, transportation and storage acquisition and management that would eliminate after-the-fact prudence reviews, thereby lowering related regulatory costs.

- Use a single, comprehensive, market-based benchmark to measure the Company's performance against the competitive natural gas sales, transportation and storage markets. Under the GCPP, Nicor Gas's total annual actual gas costs, as reflected in its PGA Clause were compared with a single, comprehensive, market-based benchmark.

- The Benchmark Gas Cost was based upon the following formula:

  Market Index Cost (Market Index Price x Sales Volumes Delivered)
  Minus: Storage Credit Adjustment
  Plus: Firm Deliverability Adjustment
  Plus: Commodity Adjustment

Attachment RAF-1 sets forth the manner in which savings and costs under the GCPP were calculated.

Q. Please compare Nicor Gas's 1996 and 1999 GCPP filings and the GCPP approved by the Commission.

A. Attachment RAF-2 is a summary of the key components of the 1996 and 1999 GCPP filings, as proposed by the Company, as well as the GCPP that was ultimately adopted by the Commission. In particular, the change to the Storage Credit Adjustment made by the Commission in approving the GCPP had very direct operational implications for Nicor Gas in its efforts to manage its storage operations to the GCPP benchmark. As approved, the GCPP established a fixed pattern of monthly storage injection and withdrawal quantities that Nicor Gas had to satisfy in managing its storage operations. This element of the GCPP Benchmark added complexity and risk to the Company's ability to meet and outperform the benchmark.

V. Detailed Discussion of Findings

1. The GCPP Approved by the Commission Was Similar in Concept and Operation to the Structure of Gas Cost PBR Programs of Other Gas Utilities in the U.S.

Q. Have you made a comparison of the GCPP approved for Nicor Gas to the gas cost PBR programs of other gas utilities?

A. Yes. Appendix C presents the results of a survey conducted by NCI of gas utilities in the U.S. that have gas cost PBR programs. Using this PBR survey information and the information I presented earlier on the purpose, design, and mechanics of the GCPP, I compared the key features of other approved gas cost PBR programs to those of the GCPP approved for Nicor Gas.

Q. What did you conclude based on your comparison?

A. I concluded that the GCPP approved for Nicor Gas was similar in concept and operation to the gas cost PBR programs of other gas utilities.

Q. Please explain how you reached this conclusion based on the comparison of PBR programs you just mentioned.

A. My first step was to review the key features of the various gas cost PBR programs contained in Appendix B. I have defined "key features" to encompass the purpose, design, and mechanics of the particular PBR program, and used these key features to structure the format of Appendix B and facilitate a comparison of these PBR programs to the GCPP approved for Nicor Gas. Referring to Appendix B, I established the following seven categories for purposes of comparison: (1) Program Term; (2) Incentive Structure; (3) Benchmark; (4) Tolerance Band; (5) Sharing Mechanism; (6) Benefits Achieved; and (7) Review Process.

As a next step, I described the broad and common features observed in the gas cost PBR programs included in Appendix B. This step was facilitated by my review of the available supporting documentation for the various PBR programs, including: tariff sheets, regulatory decisions, program review reports, and trade publication articles. The results of this assessment are provided below:

(1) **<u>Program Term</u> –** ranged from one year to eight years, with the typical term averaging three years. In certain cases, the PBR program was deemed to be permanent, with automatic extension occurring annually unless otherwise terminated and/or modified by the regulatory commission.

(2) **Incentive Structure** – ranged from a narrow focus on the utility's commodity gas procurement activities to a broader, more comprehensive focus on the utility's overall gas supply portfolio (e.g., gas commodity, pipeline transportation, storage). More than one-third of the approved PBR programs had an incentive structure based on the utility's overall gas supply portfolio while the remaining portion of the programs were based on incentives dealing with the utility's commodity gas procurement function.

(3) **Benchmark** – designed consistent with the nature of the incentive structure. In all cases, the benchmark was tied to one or more publicly available gas price indices, with commodity purchase pricing points established either at the relevant production wellhead/basin or the utility's city-gate(s). Typically, the commodity benchmark reflected a mix of First of the Month ("FOM") and average daily gas prices. For the interstate transportation component, the benchmark typically reflected historical reservation charges, and in some cases, reflected the variable component of the transportation charges from the wellhead/basin to the city-gate.

(4) **Tolerance Band** – approximately 60 percent of the PBR programs had some type of tolerance band. Most tolerance bands were symmetrical (i.e., equal treatment for savings and costs), with the typical range around the benchmark price established at between one and two percent. In my view, a tolerance band was not a significant differentiating point in a gas cost PBR program. However, if a PBR program does not contain a tolerance band, all other things being equal, the program will exhibit a higher degree of risk for the utility. This occurs when actual gas costs are greater than the benchmark (up to the high-end of the tolerance band), the utility will not recover the full cost of its gas purchases because of the sharing provisions of the PBR program. Under a PBR program with a tolerance band, the utility is assured full recovery of its purchased gas costs to the extent such costs are within the tolerance band, since no sharing occurs.

(5) **Sharing Mechanism** – approximately half of the PBR programs had a fixed percentage for the sharing of savings and costs between the utility's customers and shareholders. For the other programs, the sharing percentages varied on a progressive basis, with greater sharing for the utility's shareholders occurring in most programs as the total annual savings increases. In certain programs, the sharing percentages were different (i.e., asymmetrical sharing) for achieved gas cost savings compared to the incurrence of additional gas costs.

(6) **Benefits Achieved** – Where specified, the benefits achieved varied widely among PBR programs, with annual benefits ranging between zero and $37 million (before sharing). In some cases, total benefits were reported over the duration of the program (e.g., over a three-year period) in recognition of the longer time period required to realize the full value from the PBR program. In general, the PBR programs that had incentives structured on a comprehensive gas supply portfolio basis tended to result in increased benefits (in absolute terms) compared to the more narrowly focused, commodity gas procurement structures. This was not surprising considering that the total gas costs covered under the comprehensive programs also were relatively higher reflecting all three components of the gas utility's supply and capacity portfolio.

(7) **<u>Review Process</u>** – approximately half of the PBR programs are reviewed on an annual basis (with two programs reviewed every 6 months), one-third of the programs are reviewed every two-three years, and the remaining programs are reviewed on an unspecified periodic basis. Where specified, the review consisted of a report submitted by the utility assessing the past performance of the PBR program and the need for any modifications to the program.

The final step in the process was to compare the purpose, design, and mechanics of the GCPP to the broad and common features of the other gas cost PBR programs. This enabled me to determine the similarities and differences, if any, between the GCPP and the gas cost PBR programs of other gas utilities.

Q. Please discuss your findings with regard to the purpose of the GCPP compared to the stated purpose(s) of the other gas cost PBR programs.

A. The incentive structures of the other gas cost PBR programs all were designed to provide the utility with an incentive to achieve a cost of gas that was at or below the prevailing market prices for natural gas, by establishing an annual benchmark price. This purpose was entirely consistent with the stated purpose of the GCPP that created appropriate economic incentives for the Company, with a reasonable balance of risk and reward. This established an objective standard so that the Company's customers were provided with the best gas prices available, consistent with the need for reliability of service and security of supply.

Q. Please discuss your findings with regard to the design and mechanics of the GCPP compared to those same aspects of the other gas cost PBR programs.

A. The design and mechanics of the GCPP were very similar to those of the other gas cost PBR programs. First, the incentive structure in the GCPP approved for Nicor Gas was based on a comprehensive gas supply portfolio approach. This approach is consistent with the general incentive structure of the other PBR programs and is very similar to more than one-third of the specific incentive structures of the other programs. Second, the benchmark established in the GCPP was entirely consistent with the design of the benchmarks included in the other PBR programs. Third, the sharing mechanism in the GCPP was designed on a fixed percentage basis, as were half of the other PBR programs. In addition, the GCPP also relied upon publicly available gas price indices and historical cost data for the firm deliverability component of the benchmark price. Finally, the three-year term in the GCPP fell within the range of program terms observed in the other PBR programs, and was identical to the typical program term of three years.

Q. Please discuss your findings with regard to the operation and results of the GCPP compared to those elements of the other gas cost PBR programs.

A. The benefits derived (on a restated basis) from the GCPP, and its review process, were consistent with those of the other PBR programs in terms of magnitude, recognizing the two types of incentive structures for the programs and the varying sizes of the gas utilities with such programs.

2. In its Approval of the GCPP, the Commission Did Not Require Nicor Gas to Share or Make Public The Specific Strategies and Tactics that it Would Use to Manage its Gas Resource Portfolio Under the GCPP

Q. In approving the GCPP, what did the Commission conclude regarding the sharing or making public of any information on Nicor Gas's gas resource portfolio strategies?

A. The Commission's Order approving the GCPP ruled that "specific information about the steps which Nicor Gas will take to save money" is not required for approval of the GCPP, and stated that, "Section 9-244 does not require that mechanisms which may generate customer savings be specifically articulated."[1] This ruling was in response to a claim made by the two intervenors in the proceeding (who are also intervenors in the current proceeding) that, "the Commission cannot approve the GCPP without knowing exactly what steps Nicor Gas will take to reduce gas costs." The Commission noted that, "Section 9-244 contains no such requirement." It further stated that, "imposing such a requirement would unnecessarily complicate and prolong cases under Section 9-244 and would impede the flexibility that incentive regulation is supposed to create." As stated above, the Commission agreed with the Company's position on this point.

Q. Under other gas cost PBR programs you reviewed, did gas utilities typically provide in advance of regulatory approval the details of any specific strategies and actions they would take to reduce gas costs?

A. No. The gas utilities with approved gas cost PBR programs did not provide to parties the specifics of any intended strategies and actions for managing their gas supply portfolios. Under a PBR-type regulatory framework, it is a fundamental premise that a more light-handed regulatory approach will be adopted. A key success factor under any

[1] ICC Order in Docket No. 99-0127, dated November 23, 1999, at page 39.

PBR program is to provide utility management with sufficient flexibility to foster innovation and creativity among its staff. It is the opportunity for real financial rewards that provides the necessary incentives to the utility to develop strategies and tactics. Inherent in the establishment of the PBR benchmark itself is the recognition that it constitutes the primary measure of success for the utility, which should not be constrained otherwise by a detailed review and subsequent approval of specific utility plans. Recognizing the unregulated nature of other gas market participants, and the relative operational freedom they possess, it is imperative that gas utilities operating under a PBR regime be given greater freedom and managerial prerogatives than under traditional regulation.

Q. Does the information that you have reviewed demonstrate how Nicor Gas would operate the GCPP and manage its gas supply portfolio to derive benefits under the GCPP?

A. Yes, it does. The information necessary to identify the potential risks, the possible ways of mitigating those risks, and the opportunities to maximize the benefits to be shared under the GCPP was available throughout the Company's GCPP and PGA filings and other publicly available documents. In particular, any information that described the GCPP Benchmark Price, its derivation, and its computational details, provided important insights into how Nicor Gas would need to manage its gas supply portfolio to derive benefits for its customers and shareholders under the GCPP.

Q. Do these types of broad strategies constitute all the activities undertaken by Nicor Gas to manage its supply portfolio under the GCPP?

A. No. However, it is important to first distinguish between a gas utility's gas supply "strategies" and its gas supply "tactics" because they have very different implications for purposes of gas supply planning and procurement activities. "Strategies" can often be envisioned in advance of implementation, but only in broad terms. "Tactics" are short-term actions or tools that are responsive to the short-term dynamics of the marketplace. As such, what tactics will be used often cannot be established "before the fact" considering the uncertainties and changing conditions of the gas markets. Yet, Nicor Gas employed many tactical actions on a day-to-day basis that had to evolve as its staff gained a better understanding of the volatility inherent in the natural gas markets, and as the results of their actions could be reviewed and adjusted, as appropriate.

3. The GCPP Approved by the Commission Created New Risks for Nicor Gas's Customers and Shareholders that the Company Would Have to Successfully Manage to Derive Benefits under the GCPP from its Gas Supply Planning and Procurement Activities, and Recognition of These New Risks Provides an Understanding of the Approaches Nicor Gas Could Use to Manage These Risks in its Efforts to Create the Benefits for its Customers and Shareholders

Q. Would a review of the GCPP provide insights into how Nicor Gas would need to manage its gas supply portfolio to derive benefits for its customers and shareholders under the GCPP?

A. Yes. Very simply, Nicor Gas sought to derive benefits under the GCPP by managing its overall gas supply portfolio[2], and its resulting gas costs, to the GCPP benchmark. This

[2] Nicor Gas's "overall gas supply portfolio" was comprised of all of its commodity-related and capacity-related components, including its gas storage facilities and the associated stored gas volumes. This is exactly the same set of gas resources it managed under traditional PGA regulation before January 1, 2000.

included monetizing the value of its low-cost LIFO gas layers. Just as intended, the GCPP benchmark served as a target to Nicor Gas for purposes of developing its overall gas supply strategies and short-term tactical actions that would be responsive to the dynamics of the gas marketplace. As such, a closer review and understanding of the GCPP Benchmark Price provides important insights into how Nicor Gas would need to manage its gas supply portfolio to derive benefits for its customers and shareholders under the GCPP. To accomplish this, it was first necessary to understand the various new risks created under the GCPP that Nicor Gas would have to manage to be successful in its gas supply planning and procurement activities

Q. Please identify the risks placed on Nicor Gas by the GCPP.

A. The GCPP as approved by the ICC exposed Nicor Gas to new and substantial risks in three broad areas, each of which contained a subset of other risks to be managed. These risks were very different and much more challenging relative to the risks the Company faced under traditional PGA regulation. These three areas of risk were: (1) commodity risk; (2) storage risk; and (3) fixed cost risk. In addition, as I will discuss below, these risks were amplified by the extreme volatility in the gas markets during the GCPP period. To address these risks, Nicor Gas was compelled to avail itself of all available gas resource strategies, including the use of valuable Company assets, such as the low-cost LIFO layers.

Q. Please describe the commodity risk faced by Nicor Gas.

A. The commodity portion of the GCPP benchmark, as defined by the Market Index Cost, was set at a simple average of the price of gas delivered to Chicago at the FOM and daily market index ("DMI") prices during that same month, weighted 65 percent and 35 percent, respectively. These prices were determined by a number of independently reported price indices. Because this benchmark was a simple average, it assumed implicitly that commodity purchases in each month would be made at 65 percent FOM and 35 percent DMI, regardless of the monthly temperature or the daily temperature variations about the average. Further, the calculation of the DMI assumed that equal amounts of gas would be purchased on a daily basis. This created a risk between the simple daily average of the DMI and the weighted daily average of the Company's actual gas purchases. Accordingly, Nicor Gas had to manage risks that were derived primarily from uncertainties associated with weather and temperature patterns, and the amount of gas that would be used by its customers. The result was that the gas commodity portion of the benchmark was a moving target, dominated by weather.

Nicor Gas first had to decide, prior to the beginning of each month, how much gas for the month would be purchased at the FOM price. However, volatility in historical monthly temperature patterns, and the changing demands of its sales and transportation service customers, meant that Nicor Gas would not know with any certainty how much gas should be purchased for the upcoming month, prior to that month. Stated another way, to be able to meet the GCPP Benchmark Price in any month, Nicor Gas knew it would have to purchase 65 percent of its monthly gas supplies at FOM prices, but it did not know the quantity of monthly gas supply volumes to be applied to that percentage.

Second, Nicor Gas was exposed to the risk that actual temperatures were not the same as forecasted temperatures. Since the Company's gas requirements increased by approximately 35,000 MMBtu for each unit of increase in heating-degree days ("HDDs"), this commodity risk was substantial. To provide a simple example, if the actual HDDs on a given day were higher by four units than forecast, Nicor Gas would have had to purchase an additional 140,000 MMBtu of gas at daily prices, or, if allowed operationally, to withdraw more gas from storage. If the price difference between FOM gas and DMI gas was $0.50 per MMBtu, Nicor Gas was exposed to approximately $70,000 of price risk in just one day. Added to this complexity was the fact that the average of the daily gas prices (the DMI price component) was not known until after the end of the month.

Finally, the Company had to manage the risk associated with its level of lost and unaccounted-for gas ("LUA"). Because the GCPP Benchmark was based on delivered gas volumes while actual gas costs were based on purchased gas volumes, even if all the Company's gas purchases were made at the GCPP's Market Index Prices, there could be a GCPP loss resulting from this volumetric mismatch. While it can be argued that the Commodity Adjustment implicitly accounted for LUA, the fact still remains that Nicor Gas had to manage the risk of an increasing level of LUA within the confines of the GCPP Benchmark. As a result, Nicor Gas could attempt to manage this risk through any operational actions that could reduce its future level of LUA and by hedging the estimated LUA gas quantities.

Q. Please describe the storage risk faced by Nicor Gas.

A. In the management of its storage resources, Nicor Gas faced risks that arose from the structure of the Storage Credit Adjustment ("SCA"), use of storage by its transportation service customers, and the use of a Last-In, First-Out ("LIFO") methodology for storage accounting on an annual basis. The result was a moving benchmark that was unknown until the end of the year; driven primarily by the combination of temperature patterns, market activities of transportation service customers, uncertainty in the Market Index Price, and storage costs that would remain unknown to Nicor Gas until the end of the calendar year.

The approved GCPP included an SCA that was intended to adjust the Market Index Price to reflect the difference in the cost of gas purchased in the summer, for withdrawal in the winter, compared to the winter gas prices of flowing gas supplies. Costs were assigned to the gas volumes injected or withdrawn using the Market Index Price in effect at the time of injection and withdrawal, and weighted by a pre-determined injection and withdrawal schedule. While Nicor Gas had some limited ability to vary the timing of injections and withdrawals to try and match these price weightings, the weather, actions of other transporters on the Nicor Gas system, and the operational constraints of its storage fields ultimately dictated the timing of storage injections and withdrawals.[3]

Compounding the management of this storage uncertainty was the use of the LIFO inventory methodology for calendar year storage accounting. Under the LIFO method, the cost of the gas withdrawn on January 1st of each year was the average cost of all gas purchased during the same calendar year, and would not be known until the end of the current calendar year. Accordingly, Nicor Gas faced the challenge of attempting to hedge costs against the SCA that would not be known until the calendar year was completed.

Q. Please describe the fixed cost risk faced by Nicor Gas.

[3] It is important to note that the storage activity attributable to the SCA calculation was computed as the net result after Nicor Gas's transportation service customers and third party shippers had used their allotted storage rights.

A. The annual fixed costs associated with interstate transportation and storage capacity were set at a fixed level of $116,582,612. This amount included fixed costs forecast to be incurred in 2000-2001 and credits to those fixed costs obtained from historical capacity release and other capacity management activities undertaken by Nicor Gas. The potential for the actual fixed costs and credits to vary from this predetermined set amount represented an additional risk to Nicor Gas.

Q. Are you suggesting that Nicor Gas was disadvantaged because of the risks inherent in the GCPP?

A. No. Nicor Gas was not disadvantaged provided it had a reasonable opportunity to obtain a reward commensurate with the risks it was assuming. However, the necessary actions required Company personnel to be more innovative and creative in how they managed the overall gas supply portfolio to the GCPP Benchmark. In addition, due to unexpected and extreme gas market conditions, Nicor Gas personnel had to approach the implementation of these actions in a very flexible manner.

Q. Please describe Nicor Gas's approach to managing the risks associated with its efforts to minimize gas costs with respect to the GCPP Benchmark.

A. Nicor Gas approached the management of its costs and risks defined by the GCPP in a systematic fashion that focused on managing each component to minimize its costs and to secure any available benefits. My review of Company records led me to conclude that, over time, Nicor Gas staff attempted to identify the risks that they faced, and sought to develop broad strategies and specific tactical actions to address those risks. Evidence of this approach can be observed in the Company's ongoing discussions throughout the GCPP Period concerning alternative strategies to manage its gas supply planning and procurement activities. However, due to changing gas market conditions, Nicor Gas's supply procurement strategies could be characterized as being in a developmental state throughout the GCPP Period. Nevertheless, prior to the approval of the GCPP, the Company was operating on its fundamental belief that it could perform in a manner better than the GCPP benchmark, and more specifically, on its ability to outperform the Market Index Price in its ongoing purchase of gas commodity volumes.

Finally, during our review of the approaches used by Nicor Gas to manage its gas costs in relation to the GCPP Benchmark, we noted no indication that the Company ever acted in a manner that would jeopardize the reliability of its gas supply to its customers, or that created any risk of supply disruption.

Q. Please describe how Nicor Gas managed its gas commodity costs and the associated risks with respect to the GCPP Benchmark.

A. The gas commodity prices experienced by Nicor Gas varied daily with the market, while gas supply quantities varied daily based on customer demand, weather, and storage activity. Minimizing the cost of commodity purchases and managing the risk associated with the commodity meant managing the costs and risks of three components: (1) the supply area; (2) the transport "basis" (i.e., price difference between Chicago city-gate and the various gas supply locations); and (3) the fuel retained by interstate gas pipelines. There were separate costs and risks for the FOM purchases and DMI gas purchases, and these varied daily for gas purchases to be made next month and next day, respectively.

Nicor Gas generally hedged its expected commodity purchases with a combination of OTC financial products and NYMEX gas contracts. For example, prices for expected

FOM purchases on Natural Gas Pipeline Company of America ("NGPL") could be managed using NYMEX contracts plus NGPL basis contracts, buying gas or OTC contracts at NGPL supply areas, buying gas or OTC contracts at Nicor Gas's city-gate, or some other combination. Hedging the DMI volumes was difficult, since the amount of gas to be consumed was unknown prior to the month. One approach was to buy more or less FOM gas than projected, and then use NYMEX futures transactions in the following month to simulate the volume and price movement of the DMI allocation.

Q. Please describe how Nicor Gas managed its storage risk.

A. Under the structure of the GCPP, as I described earlier, Nicor Gas faced the risk that the actual storage withdrawal pattern might vary from that inherent in the SCA. To the extent the approved weightings did not match the actual withdrawal weightings, Nicor Gas might not be able to generate revenues through its PGA equal to the cost of the storage gas delivered to its customers. To manage this risk, Nicor Gas could vary some of its storage injections and withdrawals within the physical operating parameters of the storage fields, sell gas in storage to third parties, release control of certain storage contracts, or take such other actions within its control to maximize the cost savings as measured by the GCPP. Company records indicated that Nicor Gas varied injections to minimize the cost of gas injected, released storage contracts to third parties for asset management arrangements, reduced storage inventories to withdraw lower cost inventory layers, managed storage release arrangements to generate the maximum benefit, and tracked expected storage positions and costs in order to measure their exposure.

Q. Can you please explain how the Company's LIFO accounting method for stored gas affected the management of its underground and leased storage?

A. Under LIFO accounting, LIFO gas layers are formed when injections are greater than withdrawals during the same year, which results in existing gas layers not being "accessed." Conversely, LIFO gas layers can be reduced or eliminated when withdrawals are greater than injections during the same year. Due to weather patterns, gas is typically withdrawn from storage during the months of November through March and gas is injected during the months of April through October. Since LIFO accounting matches injections and withdrawals during the fiscal year, which for Nicor Gas is also the calendar year, I concluded that the opportunity for Nicor Gas to access lower-cost LIFO layers could only occur when the storage withdrawals in November and December were higher than the net of the April through October injections and the January through March withdrawals in the same fiscal year. This also suggested that the lower-cost LIFO layers became "trapped" in time, and in storage inventory, as Nicor Gas's firm gas loads changed over time and the amount of storage used for firm customers had declined over time. Under this accounting method, the only way to monetize the value of the lower-cost LIFO layers was to get them into the gas market. And selling the higher, last-in, layers was a reasonable and appropriate way to bring these low-cost layers into the market, and to allow Nicor Gas to share the associated benefit with its customers.

Q. Please describe how Nicor Gas managed its fixed cost risk.

A. The risk associated with fixed costs was that they would be higher than those included in the GCPP Benchmark. Accordingly, Nicor Gas's management of its fixed cost risk focused on keeping fixed costs low and maximizing capacity management revenues to keep fixed costs below the benchmark level. This involved managing pipeline capacity contracts, minimizing fixed cost payments, and maximizing capacity release revenues.

4. The Challenging Gas Market Conditions Experienced During 2000 through 2002, Under Which Nicor Gas was Required to Manage its Gas Resource Portfolio to the GCPP Benchmark, Reflected Very Unpredictable Weather Patterns, Unusual Swings in Gas Demand Requirements, Highly Volatile Gas Prices, and Precipitous Industry Restructuring

Q. Would you please briefly describe the gas market conditions faced by gas utilities such as Nicor Gas during the GCPP time period.

A. During the 1998 through 2002 time period, the gas market in the U.S. was a very dynamic, volatile, and challenging marketplace[4]. Changes in regional and local weather conditions[5], daily and monthly gas supply and demand balances, wellhead and delivered gas prices, and the resulting activities of gas utilities and regulators, all served to define the gas market at this time. Natural gas prices at the Chicago city-gate climbed from a low of $1.98 per MMBtu (on December 4, 1998) to a high of $15.70 per MMBtu (on December 21, 2000) within just a two-year period. Energy trading activities reached its peak in 2001 before retreating with the collapse of Enron, taking with it creditworthy trading partners and market liquidity. Regulators and gas industry participants alike struggled to deal with the almost seven-fold increase in gas prices, while frigid

[4] For example, commenting on the gas market conditions during the 2000-2001 Winter Heating Season, the American Gas Association stated, “To say the market conditions that prevailed, beginning in November 2000, were extraordinary compared to the previous decade is a significant understatement.” (American Gas Association – Energy Analysis: LDC System Operations and Supply Portfolio Management During the 2001-2001 Winter Heating Season).

[5] Both colder and warmer than normal weather conditions provide challenges for a gas utility in managing its gas supply resources to accommodate changing gas demand requirements.

temperatures persisted from December 2000 through March 2001, increasing the quantity of gas consumed at these record high prices.

To summarize the gas market during this period, Appendix D to my testimony presents an overview of the gas market conditions experienced in the U.S. during the period January 1998 through December 2002. Review of Appendix D helps one to understand the challenges faced by gas utilities in managing their gas supply portfolios during this time period.

To provide further details of these gas market conditions, Appendices D-1 through D-3 present details of the trends in monthly temperatures in Illinois, and the industry-wide trends in gas prices and gas storage activity, respectively.

Q. Why have you chosen to include in Appendix D a time period that pre-dates the filing and implementation of the GCPP?

A. I have chosen to include a time period (starting in January 1998) before the GCPP was filed and implemented to provide added insights into the market conditions that most likely influenced the thinking of all interested stakeholders during the preparatory and approval stages of the GCPP, and to provide a context for the implementation of the GCPP.

Q. Please describe the types of gas market conditions faced by Nicor Gas before the ICC approved the GCPP in December 1999.

A. Referring to Appendix D, the natural gas markets in 1998 and 1999 were characterized by low prices with low volatility, rapid growth in proprietary trading (physical and financial) by gas marketers, growth in OTC markets, domination of the wholesale gas markets by the large energy trading firms, an increased level of transportation service for the core customers of LDCs, and emergence of retail gas marketing companies. This was the result of changes that had been occurring since the early-1990s and before.

Following the issuance of FERC Order No. 636 in 1992, revised tariffs that unbundled interstate pipeline services were made effective over the next two years to implement this landmark Order. The Gas Industry Standards Board ("GISB")[6] was formed to help standardize operating protocols on interstate pipelines (subject to FERC approval) and gas markets (e.g., the GISB gas contract). The NYMEX began trading in natural gas futures contracts (10,000 MMBtu per contract) in April 1990. NYMEX marked another milestone in the energy futures markets in October 1992 when it launched options on natural gas futures, giving market participants additional flexibility in managing their market risk. The gas market also adopted the form of the standard financial contract issued by the International Swap Dealers Association ("ISDA") to conduct business in OTC markets.

FERC Order No. 637 was issued on February 9, 2000, providing further clarification to affiliate transactions and the rights of shippers, removal of price caps on capacity releases, and standardizing many of the business practices on the interstate pipelines. These changes were to be implemented by the pipelines during the summer of 2000. The standardization of gas and pipeline markets across the U.S., emergence of merchant electric generators, and the issuance of FERC Order No. 888 promoting wholesale electric competition through open access transmission services, coupled with the ISDA

[6] This organization has since become the North American Energy Standards Board ("NAESB").

and NYMEX gas futures contracts, supported the rapid growth of energy marketers during this time. These firms were adept at extracting the maximum value from energy transactions that spanned national markets—a perspective that most LDCs did not have at the time. The liquidity in OTC physical and paper markets, the popularity of the NYMEX gas contract, and the fact that natural gas was a fungible commodity made it possible for these firms to create different natural gas products and services, across time and geography, by separating the physical and financial terms, and re-combining them in ways tailored to specific markets.

Q. Please contrast these market conditions with those experienced by Nicor Gas during the time period after approval and implementation of the GCPP.

A. During the period 2000 through 2002, the gas markets exhibited much higher volatility and extremes in gas prices and weather conditions than in the prior years, as evidenced by the graphic analyses contained in Appendices D-1 and D-2. As shown on page 2 of Appendix D-2, gas prices increased in the Chicago city-gate market throughout 2000 and peaked in January of 2001. Then in the 2001-2002 winter heating season, gas prices actually inverted from the traditional higher winter price expectation. And compared to the prior period, January 1998 through December 1999, gas prices in the GCPP Period were significantly more volatile.[7] This situation is not at all surprising when you examine the weather patterns and trends in Illinois during those same periods. Referring to page 2 of Appendix D-1, during the GCPP Period, extremes in colder and

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[7] Using the coefficient of variation as a statistical measure of volatility, the gas prices experienced during the GCPP Period were over twice as volatile as the gas prices experienced during the January 1998 to December 1999 period.

warmer than normal temperatures occurred, and there was much more variation in month-to-month changes in temperatures (i.e., monthly reversals in temperatures relative to the normal temperatures), compared to the pre-GCPP period. The temperature extremes in December 2000 (November and December 2000 was the coldest such two-month period on record) and in November 2001 to January 2002 (25 percent warmer than normal) directly affected the anomalies in gas prices observed in Appendix D-2. Finally, the underground storage activity resulting from the trends in weather and gas prices is depicted in Appendix D-3. Page 1 shows that by the end of the 2000-2001 winter heating season, storage inventory levels across the U.S. were at extremely low levels (significantly below the five-year average), while at the end of the 2001-2002 winter heating season, storage levels were at their highest levels since 1994. The relative reliance on storage during those same periods, which drove the above-described inventory levels, is presented on page 2 of Appendix D-3.

Q. Please describe the types of activities undertaken by gas utilities during this period to manage their gas supply portfolios.

A. First and foremost, LDCs managed their gas resource portfolios to meet the requirements of their firm or sales gas customers. Pipeline and storage capacity that was temporarily not being used was either released or used to sell gas to third parties. In order to gain access to the benefits enjoyed by many of the larger gas marketing and trading companies, many LDCs also entered into agreements with these companies to manage their gas supply, transportation, or storage agreements, sometimes referred to as "asset management agreements". LDCs would release or otherwise assign their contracts to large marketers in exchange for a price and/or share of any profits created from various synergistic transactions. Capacity release arrangements often included the ability to buy or receive gas at specified times and quantities. These transactions included activities such as storage pre-fills; "converting" a released pipeline contract into a "no-notice type" service; and entering into a city-gate gas purchase agreement as part of a capacity release.

In general, gas utilities had to develop overall gas portfolio strategies that separately managed gas prices ("P") and gas volumes ("Q") to accommodate the changing and sometimes volatile gas market conditions, yet continued to provide the desired level of supply and service reliability for their customers.

Specific gas supply portfolio strategies included:

1. Partnerships with, or outsourcing to, third-party gas management firms;

2. Optimizing the use of storage assets (owned and leased) through capacity release or re-packaging as sales services;

3. Developing a diversified resource portfolio through a mix of pipeline capacity contracts (to access diverse supply areas) and storage contracts (to augment or hedge gas supply); and

4. Using derivative markets (NYMEX and OTC) to manage the price risk in portfolios separately from the physical supplies.

In addition, where feasible and economically viable, underground storage facilities were expanded and high-deliverability storage services were developed. These activities accommodated the increased variability in daily and monthly deliveries of gas by third-party suppliers in conjunction with increases in the number of customers electing supplier choice programs (i.e., end-user gas deregulation programs) offered by gas utilities. These activities also supported the growth in "park-and-loan" and "gas banking" services.

Q. What types of activities did state regulatory commissions undertake in response to these gas market conditions?

A. The state regulatory commissions focused on the same kinds of issues that characterized the conditions in the gas market during that time. For example, many regulators addressed the high gas prices and price volatility during 2001 through the consideration of hedging and other risk management activities. In an industry-wide survey[8] conducted by the National Association of Regulatory Utility Commissioners ("NARUC"), six jurisdictions[9] including Illinois[10] conducted special investigations into the growing concerns over high gas prices. Many of the respondents also indicated that they had already addressed how hedging mechanisms should work in relation to any existing PGA mechanism and the recovery of costs associated with hedging mechanisms.

To further address the price volatility issue, regulators worked with utilities to develop and implement other ratemaking measures designed to provide customers with an enhanced stability in their monthly and annual natural gas bills. These measures included increased participation in the utilities' existing budget billing programs, investigation and implementation of "weatherproof" billing techniques, the offering of

[8] State Responses to Last Winter's High Natural Gas Prices and Consideration of Hedging and Other Risk Management Activities, compiled by the National Regulatory Research Institute ("NRRI") on behalf of NARUC, August 2001.

[9] Besides Illinois, the other jurisdictions were Arkansas, the District of Columbia, North Carolina, Oklahoma, and Utah.

[10] ICC Notice of Inquiry ("NOI") – Docket No. 01 NOI-1 (Increase in the Price of Natural Gas), 1st Quarter 2001.

fixed price and fixed bill rate options, and implementation of weather normalization clauses.

Later in 2001, NARUC held its 113th Annual Convention[11] where it presented the topics of most interest to utility regulators and the utilities themselves. Review of the agenda indicated that the gas industry "hot topics" included gas price volatility (and how it was impacting the developing competitive markets for customer choice programs) and the appropriateness of traditional PGAs (and the use of other alternatives) in the evolving natural gas market.

The issue of PBR received increased attention during the 1999-2002 period as evidenced by the results of the NCI survey contained in Appendix C. Specifically, there were ten additional gas cost PBR programs approved by regulators in eight states during that time period[12].

Finally, LDC unbundling of natural gas services for end-use customers continued during the 1999-2002 timeframe[13], with regulators either approving new programs or fine-tuning existing programs to accommodate certain changes in the gas markets (e.g., reduced number of gas marketers, creditworthiness issues, transportation customers returning to an LDC's sales service).

Q. Were the broad activities undertaken by Nicor Gas during this time period to manage its gas supply portfolio consistent with those of other gas utilities?

[11] Held on November 11-14, 2001.

[12] Gas cost PBR programs were approved in Idaho, Indiana, Kentucky (2), Missouri, South Dakota, Tennessee (2), Washington, and Wisconsin (not including Illinois's PBR program).

[13] Including Nicor Gas's Customer Select Program for its smaller-sized gas customers.

A. Yes, they were. The activities undertaken by Nicor Gas to manage its gas supply portfolio relied upon the same types of available "transactional tools" as those commonly used by other gas utilities to manage their gas supply resources.

For example, we learned from our review of case documents and Company staff interviews that Nicor Gas actively managed its gas resource portfolio by entering into storage management agreements with Inventory Management and Distribution LLC ("IMD") and Dynegy (formerly Natural Gas Clearinghouse); utilized various risk management products to hedge its expected gas commodity purchases; released unused pipeline capacity or used it to sell gas into other markets; and released interstate pipeline capacity to customers who wanted to acquire gas on their own.

5. The Company's Use of its Low-Cost LIFO Layers in Underground Storage was a Reasonable, Appropriate, and Effective Risk-Mitigation Strategy for Managing its Gas Resource Portfolio to the GCPP Benchmark, and for Deriving Benefits for its Customers and Shareholders

Q. In evaluating the Company's use of its low-cost LIFO layers, was it first necessary to make an assessment of the ownership rights associated with this gas resource?

A. Yes, it was.

Q. What have you concluded with regard to the ownership rights to Nicor Gas's low-cost LIFO gas layers?

A. I have concluded that the low-cost LIFO gas layers were, and remain, the assets of Nicor Gas.

Q. Please explain the reason for your conclusion.

A. My conclusion is based upon my review of the nature and origins of the low-cost LIFO gas layers contained in Nicor Gas's owned and leased storage fields, the general economic and regulatory principles surrounding ownership of utility assets, and my extensive experience in the gas utility industry.

Q. Please describe the nature and origins of the low-cost LIFO gas layers contained in Nicor Gas's owned and leased storage fields.

A. Nicor Gas stores gas for its customers in seven aquifer storage fields it owns, and leases additional storage capacity from NGPL. The Company uses the LIFO accounting method for purposes of tracking its storage transactions[14]. Under this method, if more gas is injected than withdrawn in a particular year, a new storage inventory layer is created with a unit cost based on the average cost of gas injected for that year[15]. If more gas is withdrawn than injected, previous storage layers are eliminated together with the associated costs that were established at historical gas price levels.

As depicted in Attachment RAF-3, at December 31, 1999[16], Nicor Gas had 89.7 million MMBtu of gas in storage for its sales customers at an average cost of $0.80 per MMBtu. This inventory was composed of 12 separate LIFO gas layers, with unit costs ranging from $0.25 per MMBtu to $3.23 per MMBtu. Three gas layers for the years 1968, 1970, and1984 represented two-thirds of Nicor Gas's total gas storage inventory. While the 1984 layer was only 17 percent of the Company's total gas volumes, at a unit cost of

[14] The LIFO gas layers in storage are reflected as "Current Assets" in Nicor Gas's Consolidated Balance Sheet, and characterized as "Gas in storage at LIFO cost."

[15] The cost of gas injected into storage is valued at the Company's average annual cost of gas, as calculated at the end of the calendar year.

[16] The start of the GCPP Period.

$3.23 per MMBtu, it represented approximately 68 percent of its total inventory cost. As a result, the remaining 74.5 million MMBtu of gas inventories had a unit cost of $0.30 per MMBtu, which was much lower than the average cost of gas in storage.

Given the much higher gas prices at the time the GCPP was proposed, and the common knowledge of the Company's low-cost LIFO layers, the inherent benefit of these LIFO layers to the Company and its customers should have been apparent to all interested parties.

Q. Was Nicor Gas able to access the low cost LIFO layers during the term of the GCPP?

A. Yes. Attachment RAF-3 depicts the year-to-year storage decrements or increments during the term of the GCPP. Based on the restated GCPP results, during calendar year 2000, Nicor Gas eliminated the entire 1984 gas layer and part of the 1973 gas layer, at an average cost of $2.87 per MMBtu. Due to the warmer than normal weather in calendar year 2001, Nicor Gas established a new LIFO gas layer at an average cost of $5.13 per MMBtu. In calendar year 2002, due to colder than normal weather conditions in the second half of the year, Nicor Gas eliminated the 2001 gas layer, the 1973 and 1971 gas layers, and part of the 1970 gas layer. The average cost of the LIFO decrement in 2002 was $1.32 per MMBtu.

Q. Historically, how did Nicor Gas acquire the gas it injected into storage for future use by its sales customers?

A. At the end of each storage withdrawal season, the Company planned to refill its storage fields (during the traditional refill months of April through October) with gas supplies it acquired under a combination of long-term and short-term gas contracts. In addition, the Company would periodically enter the gas spot market and contract with various gas suppliers to purchase gas supplies for injection into its storage fields to take advantage of favorable, short-term gas prices.

Q. Under LIFO storage accounting, is it likely that gas supplies purchased by Nicor Gas can remain in storage for an extended period of time before its sales customers ultimately consume the gas?

A. Yes. Attachment No. RAF-3 shows that there can be a long lag time between the injection of gas into storage and the subsequent withdrawal of gas to meet customers' current needs. For example, a portion of the gas consumed by customers from storage in 2002 was provided from gas supplies purchased by Nicor Gas as far back as 1970. This Attachment also shows that there were eight gas layers in Nicor Gas's storage fields dating back prior to 1970 that were not reduced in size during the GCPP Period, and may never be reduced in future years.

Q. Please explain the economic and regulatory principles surrounding ownership of utility assets.

A. The combination of private ownership and public control is a fundamental and underlying principle of the public utility concept. While an investor-owned utility company has an obligation to serve its customers, it also has a legally binding duty to uphold its fiduciary responsibility to its shareholders. The shareholders invest in a utility with the expectation that it will use their capital to increase share value. The customers have contracts with the utility, for a specified tariff price and defined service. They purchase services at a price that covers the utility's cost of using its assets,[17] thereby paying for the use of the facilities (including operating costs) that the utility requires to deliver service. However, these payments do not constitute an investment made by customers that entitles them to ownership or control of the utility's assets.

A utility's customers are not its owners. If the reverse were true based on the theory that by paying for the use of the assets the customers somehow acquired an ownership interest in the assets[18], it would imply that the utility owned no tangible assets, and instead would serve only as the operator of the gas or electric distribution system. Obviously, that is not the case at all.

Q. What rights are conferred upon a utility's customers through their ongoing payment of utility rates?

A. Through its ongoing payment of rates, the customer is simply paying for service it is entitled to under an agreement it has with the utility. Beyond that, the customer receives no rights related to ownership of the utility's assets.

Q. Why do you conclude that Nicor Gas's use of its low-cost LIFO layers was a reasonable, appropriate, and effective risk-mitigation strategy?

[17] Utility assets are defined as the cash-value assets owned by a utility, and they can include both capital and non-capital investments.

[18] In its broadest terms, this theory effectively means that anyone who bought a vehicle from General Motors ("GM") - and not GM's shareholders - actually own GM's plants and facilities because GM used the revenue stream it received from the sale of vehicles to pay for the costs of its plants and operating expenses, and to support a profit margin.

A. This approach enabled Nicor Gas to access and monetize a valuable Company-owned asset, the gas supplies "trapped" in its low-cost LIFO layers, and to share the realized value with its customers through the GCPP. Moreover, it was a reasonable risk management practice for a gas utility such as Nicor Gas to rely upon its gas storage assets in periods of high market volatility to minimize the level and variability of the gas costs incurred to serve its sales customers. The low-cost LIFO layers were an integral part of Nicor Gas's overall gas supply portfolio and the derivation of the GCPP benchmark reflected the totality of the resources included in the Company's gas supply portfolio.

Q. Was information available regarding the existence and unrealized value of Nicor Gas's low-cost LIFO layers for their eventual use in the GCPP?

A. Yes. There were many instances before approval of the GCPP in November 1999 where ready access existed for the information necessary to understand the availability and unrealized value of Nicor Gas's low-cost LIFO layers in underground storage. This information was contained in various regularly filed documents and publicly available documents such as the Company's Securities and Exchange Commission ("SEC") filings.

Q. Can you describe the types of documents you are referring to and the nature of the information contained in those documents?

A. Yes. First, each year the Company files an Annual Report of Electric Utilities Licensees and/or Natural Gas Utilities – Form 21ILCC. This document provides information on the Company's underground storage activities, including statistics on the beginning-of-year and end-of-year storage inventory balances, and their associated costs. Any net reduction in inventory (i.e., storage withdrawals greater than injections) would be reflected in this document.

Second, the Company regularly submits documents to the SEC, which I believe are provided to the Commission. In the Company's Form 10-K report, which is publicly available, there is a section in the Notes to the Consolidated Financial Statements where the estimated replacement cost of gas in storage is provided. This amount reflects the difference between the prevailing market prices for natural gas and the historical costs of gas at the time gas volumes were injected into storage. This amount represents the magnitude of the trapped value in storage available to Nicor Gas through its low-cost LIFO layers.

Third, in the Company's last base rate case, Docket No. 95-0219, the ICC Staff presented testimony on a rate base adjustment to Nicor Gas's working gas inventory. The direct testimony of Eric Lounsberry discusses this adjustment and points out that the adjustment should be made using a LIFO inventory valuation method since that is the method used by the Company. As part of his testimony, Mr. Lounsberry referred to various data request responses provided by the Company that presented the details of the LIFO method of storage inventory accounting, including a tabular workpaper summary (Response to ICC Data Request No. RK-63) depicting the Company's 20 LIFO layers in storage at that time, with unit prices and gas quantities for each LIFO layer.

Finally, in its Customer Select proceedings, Docket Nos. 00-0620 and 00-0621, the Company presented an explanation and exhibits of its LIFO storage accounting procedures. Company witness Al Harms described in his direct testimony the manner in which the LIFO layers were created, and how they changed over the course of a calendar year. In addition, he referred to workpapers given to the ICC Staff that illustrated how the gas in storage by LIFO layer was calculated by month, and how the underlying costs and gas balances would change over time.

These documents clearly indicate that ample information was available regarding the Company's investment in low-cost storage gas, its potential availability as a gas supply resource of the Company, and the unrealized value this asset represented.

6. Under Nicor Gas's Management, the GCPP Yielded a Substantial Benefit to its Customers of Approximately $53 Million, and These Gas Cost-Related Benefits Would Not Have Been Realized in the Absence of the GCPP

Q. What benefits did Nicor Gas's customers receive from the GCPP?

A. Nicor Gas's customers received three distinct types of benefits from the GCPP. The first type consisted of the savings generated by the difference between Nicor Gas's actual gas costs and the benchmark gas costs, to the extent its actual gas costs were below the benchmark level, with those savings divided equally between its customers and shareholders.

The second type of benefit was derived from the relative price level inherent in the benchmark itself. As approved by the ICC, this benchmark contained a "threshold level" of gas costs that Nicor Gas had to at least meet before its shareholders could begin sharing in any gas cost savings. Nicor Gas's ability simply to manage and lower its gas costs down to the level of the benchmark was a benefit to its customers.

The third type of benefit consisted of various qualitative benefits related to the enhanced management and operation of Nicor Gas's gas supply planning and procurement function.

Q. What level of savings has the GCPP generated for the Company's customers?

A. Over the three years of the program, the GCPP has generated approximately $53 million in total savings for Nicor Gas's customers - $9 million by the Company outperforming the GCPP Benchmark and $44 million from lowering its gas costs towards the GCPP Benchmark[19]. These savings are presented in Attachment RAF-4 and are based upon the restated results after adjustment for the various accounting issues raised in the Report to the Special Committee of the Board of Directors of Nicor Inc. prepared by Mr. Scott Lassar and the accounting firm of KPMG LLP (commonly referred to as "the Lassar Report"). Page 2 of Attachment RAF-4 also presents the savings under the GCPP prior to restatement for 2000 and 2001. This level of savings is clear evidence that the GCPP has fulfilled its overall objective—to provide lower gas costs to the Company's customers.

Q. Please explain the benefits associated with Nicor Gas outperforming the GCPP Benchmark.

A. Referring to page 2 of Attachment RAF-4, Nicor Gas achieved a benefit by outperforming the GCPP Benchmark over the three-year GCPP Period. This benefit

[19] The achieved savings from the GCPP represented a relatively small portion of the more than $1 billion in annualized purchased gas costs incurred by Nicor Gas.

consisted of total gas cost savings of $17,746,399, of which $8,873,200 (50 percent) accrued to Nicor Gas's sales customers.

Q. Please explain how the relative price level inherent in the GCPP Benchmark produced significant benefits for Nicor Gas's customers.

A. Nicor Gas's ability to decrease its gas costs from historical levels towards the lower cost of gas inherent in the GCPP Benchmark provided significant benefits to its sales customers. The magnitude of these benefits were derived from a review of the Company's level of gas costs achieved historically relative to the level of the GCPP Benchmark that would have existed each year during the same historical period.

Q. How did Nicor Gas's actual gas costs prior to the inception of the GCPP compare historically to the corresponding GCPP Benchmark prices?

A. Page 3 of Attachment RAF-4 presents a comparison of actual gas costs for the period 1994 through 1999 to the corresponding benchmark gas costs. As shown in this Attachment, over the six-year period, actual average gas costs were $0.1136 per MMBtu higher than the average benchmark gas costs. Applying this difference to the actual delivered volumes for the three-year GCPP period (2000 through 2002) indicates that Nicor Gas would have to lower its gas costs by approximately $29 million each year[20] just to meet the benchmark.

Q. Can you explain what this result implies for Nicor Gas's required performance relative to the GCPP Benchmark and the level of benefits that would be derived under the GCPP?

[20] Or $87.5 million over the three-year period, one-half of which directly benefits Nicor Gas's sales customers.

A. This result means that just to meet the established benchmark price, Nicor Gas would have to procure gas supplies consistently below the prevailing market prices for natural gas. In other words, reaching the GCPP Benchmark was by no means a certainty to Nicor Gas, but incorporated a significant "stretch factor" and, therefore, constituted an additional level of risk that the Company was required to assume and manage under the GCPP.

In addition, from this analysis it can readily be inferred that under the GCPP, the opportunity to generate savings for both customers and shareholders was not symmetrical. During the historical period in Attachment RAF-4, the Company's actual gas costs in four of the five years would have exceeded the GCPP Benchmark. In those four years, Nicor Gas's shareholders would have had to "fund" half of the difference in increased gas costs (relative to the benchmark price level) so that its customers would receive the resulting benefits (i.e., a reduced level of gas costs) expected under the sharing mechanism of the GCPP.[21] Based on the larger annual reduction in gas costs required during 2000 through 2002 needed just to meet the GCPP Benchmark, the Company's customers received an additional benefit of approximately $14.6 million per year as a result of the "stretch factor" inherent in the GCPP benchmark[22].

Q. Is there specific evidence related to the structure of the GCPP Benchmark to conclude that the Benchmark incorporated this type of a "stretch factor"?

[21] Under the GCPP, if actual gas costs were above the benchmark, Nicor Gas's shareholders would "fund" the resulting benefits to its customers through decreased gas costs recoverable in the next year's PGA. If actual gas costs were below the benchmark, Nicor Gas's customers would "fund" the resulting benefits to its shareholders through increased gas costs recoverable in the next year's PGA.

[22] Every reduction in the GCPP Benchmark caused by a "stretch factor" would effectively require Nicor Gas's shareholders to "fund" a larger portion of the benefits to its customers before reaching the benchmark.

A. Yes. As proposed by the Company, the GCPP benchmark contained a Commodity Adjustment that was to account for the difference in its actual commodity gas costs and the market index costs included in the benchmark. The Company proposed a Commodity Adjustment of $0.049 per MMBtu based on the average of each year's actual commodity adjustments for 1994 through 1998 (excluding 1996). In its Order, the Commission lowered the Commodity Adjustment to $0.0168 per MMBtu. When viewed within the context of the historical period, this change effectively shifted approximately $4.5 million per year of risk[23] to Nicor Gas by requiring it to achieve a $9 million decrease in its actual commodity costs before triggering any shared savings for its shareholders.

Q. Please describe the nature of the qualitative benefits received under the GCPP.

A. Under traditional rate of return regulation, and more specifically under its traditional PGA mechanism, the Company is allowed to recover all prudently incurred costs. Therefore, Nicor Gas's gas supply personnel focused on purchasing gas supplies in a prudent manner to ensure recovery. Under the GCPP, Nicor Gas's personnel were motivated to be more aggressive and innovative with regards to the management of the gas supply planning and procurement function. The benchmark index effectively represented the ceiling in terms of gas costs, if the Company were to benefit from the GCPP. The gas buyers had to identify new ways to obtain gas supplies at a cost below the benchmark. Nicor Gas was forced to become better planners (both strategically and tactically) with regards to system gas requirements and how to meet those system

[23] [($0.0490 - $0.0168) x (normalized annual firm sales volumes of 280 Bcf) x 50% sharing]

demands. The Company also had to identify operational, as well as financial enhancements to potentially share in any cost savings. Nicor Gas personnel were required to improve their knowledge and ability to efficiently manage the Company's gas supply-related assets (such as on-system storage), without compromising the reliability of service historically provided to its customers. Finally, the Company explored joint ventures and other business relationships with gas industry participants to obtain additional expertise that did not reside within Nicor Gas.

Q. Will certain of these qualitative benefits continue to accrue to Nicor Gas's customers even though its GCPP is no longer in operation?

A. Yes. The knowledge transfer gained by the Company's gas supply staff from the business relationships with other gas industry participants, and the decision-making experience gained from the group's day-to-day activities, will provide long-lasting benefits to Nicor Gas's customers. This valuable knowledge base readily translates into an enhanced ability to anticipate gas market trends, increased transactional sophistication on the part of Nicor Gas's staff, and a more thorough understanding of the strategies and tactical actions that can help to effectively manage its gas supply portfolio. These staff attributes are important ingredients to the Company's future ability to minimize its total cost of gas, in its continuing efforts to provide safe and reliable gas service to its customers at a reasonable cost.

Q. Based on your understanding of the gas cost-related benefits derived under the GCPP, could these benefits have been realized by the Company's customers in the absence of the GCPP?

A. No. In my opinion, it is highly unlikely that such benefits would have accrued to Nicor Gas's customers without the GCPP for one important reason. In the absence of the GCPP, a utility such as Nicor Gas simply does not have the same economic motivation it had under the GCPP to undertake the types of innovative gas procurement strategies that can significantly benefit both its customers and shareholders.

If we examine Nicor Gas's historical gas cost performance (as in Attachment RAF-4), it is clear that under the Company's past gas procurement strategies, it would not have been able to lower its gas costs to the level of the GCPP Benchmark, let alone to outperform the Benchmark. While I agree that Nicor Gas may have had at that time the strategic and tactical "tools" to more aggressively manage its gas supply portfolio, what it lacked were the proper economic incentives, a defined benchmark or target, and the proper managerial mindsets needed to adopt the type of risk/reward profile required to implement more innovative and aggressive strategies and tactical actions for its gas supply portfolio. Under traditional PGA regulation, the "best you can do" is for the utility to fully recover its cost of gas (on which it earns zero return). This ever present, after-the-fact, prudency risk cannot begin to provide the proper incentives to motivate management to strive for superior performance.

Finally, Nicor Gas operated under the GCPP during a very challenging period for gas markets. With the changing weather conditions, price volatility, and fluctuations in end-user gas transportation loads, it is my opinion that Nicor Gas could not have achieved the success it did without the strong financial incentives to perform that, in turn, created the changed staff behaviors that supported the required level of performance.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes it does.